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Demand Responsiveness in Electricity Markets

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of other members of the Federal Energy Regulatory Commission, any individual Commissioner, or the Commission itself.

Executive Summary

Introduction

Allowing customers the opportunity to react to pricing signals, or stated differently, allowing a “demand response” in the electricity marketplace can promote efficient long-run investment, help mitigate short-run market power by generators and transmission owners, reduce price spikes, lower price volatility and reduce customers' bills. Efficiency in electricity markets will increase when customers can adequately react to price changes in the markets that result from resource scarcity and market power.

Measurement of Demand Responsiveness

Customers react to changes in prices that they see by adjusting their desired quantity of demand. As prices rise, customers will reduce the quantity demanded. As prices drop customers will increase the quantity demanded. The responsiveness of customers to price changes is characterized by their “price elasticity of demand.” Research has attempted to measure electric customers' responsiveness to changes in price. While precise demand elasticity estimates vary, there is uniform agreement that industrial, residential and commercial electricity customers can, and will, respond to the price signals they face. This response is vital to the allocation of electric resources in peak demand periods. Unfortunately, many end-customers currently face a fixed retail price and have little incentive to react to fluctuations in the wholesale price of electricity.

An important distinction can be made about the ability of customers to react to pricing signals. In the present or “short-run,” customers must use their existing infrastructure, technologies and resources to react to changes in prices. Thus their ability to react to the price changes is lower in the short-run than in the more distant future or “long-run,” when customers can adapt with technologies and future innovation. As such, it can be expected that given the proper price signals, demand responsiveness should increase over time as customers are given the opportunity to react to them..

Demand Elasticity in Market Power Analysis

In the presence of market power, suppliers have the ability to set prices above the cost of the last unit produced. The suppliers' ability to raise prices above costs increases with lower demand responsiveness. Consequently, the profit incentive of a supplier with market power to raise prices above their costs also increases as the responsiveness of demand decreases. Unfortunately, this pricing behavior further reduces the efficiency of the market by creating an even larger wedge between the actual costs of electricity production and its value to customers.

The exercise of market power also results in large price spikes and increased price volatility. In times of electricity shortage without market intervention, suppliers literally have the opportunity to “name their own price.” These prices above cost result in large wealth transfers from electricity buyers to sellers. While these wealth transfers are not necessarily a source of short-run inefficiency, the equity of such activity can be debated.

Analysis by the Commission has not focused attention on the importance of demand side response in mitigating the inefficient pricing that results from market power. The Commission's current market power tests, the Delivered Price Test, and Supply Margin Assessment (SMA) do not evaluate potential demand responsiveness within the markets. In fact, the SMA essentially assumes that market demand is unresponsive or perfectly inelastic. Increased demand responsiveness can have significant impact on the ability of suppliers to exert market power. Demand response must ultimately come from retail customers. While the Commission has very little direct jurisdiction over retail electricity markets, conditioning market based rates and merger applications on market demand responsiveness could have encouraging results in moving retail markets toward better demand response mechanisms.

Retail Rate Options in Wholesale Electric Markets

Numerous pilot programs have been enacted in recent years and have provided valuable insights into retail rate programs that promote greater demand response to price, and thus a more efficient electric market. These programs rely on innovative pricing plans and terms of service to provide retail customers with an improved set of incentives in the electric marketplace. The more the wholesale electric market demand reflects the value customers place on electricity, the more likely efficiency will come from the electricity marketplace.

Technical Issues in Demand Responsiveness

Technological progress is providing the tools necessary to allow better demand response and help create more efficient energy markets. Several new technologies make it easier for customers to react to and participate in the electric market. Economic metering technology now allows the metering of some electrical customers in real time. Systems are also being developed to communicate the pricing signals from the marketplace that customers need in order to evaluate and coordinate their consumption decisions. Distributed generation advances are providing opportunities for customers to provide increased reliability and supplemental capacity in times of high scarcity and electric prices. As technology and innovation further develop, we can expect to see greater opportunities for demand responsiveness in the marketplace.

Conclusion/Summary

Past market designs and regulation have not promoted innovations in developing opportunities for demand side responses in electricity markets. The market rules in place today within ISO's are poor substitutes for the benefits obtained from real demand response. The volatility in wholesale markets has demonstrated the importance of a demand response in times of scarcity. Demand responsiveness plays a vital role in increasing efficiency and reducing price volatility in the electricity markets. It allows customers to communicate the value of electricity to the market. Currently, advances in technology are leading to innovative pricing structures and generation alternatives to allow customers to better respond to prices. This can benefit all consumers by promoting efficiency and stability in electricity markets.

I. Introduction

Allowing customers to react to pricing signals, or stated differently, allowing a “demand response” in the electricity marketplace can promote efficient long-run investment, help mitigate short-run market power by generators and transmission owners, reduce price spikes, lower price volatility and reduce customers' bills. In the past, vertically integrated utilities provided the vast majority of retail customers with electricity using single rate electricity service. Most customers paid one price each month for electricity independent of the time related differences in generation costs or scarcity.

The movement toward deregulation in the electricity markets has brought with it large fluctuations in wholesale electricity prices. When not the result of market power, these prices generally reflect the scarcity of the electricity at a given point in time and are based on the marginal costs of the last unit of generation. Currently, only the supply side has the ability to react significantly to the price signals in the marketplace. Generation of electricity increases with higher prices and decreases with lower prices.

As a result of technological and regulatory barriers, the majority of electricity pricing plans do not allow end users to see and react to the actual market value of their electricity consumption/conservation. Since end-users do not face the real-time market price in making their consumption decisions, there is little demand reaction to changes in real time wholesale electricity prices. This lack of demand side response results in inefficient market outcomes. End users consume more than the efficient level of electricity when the prices they face are below the cost to supply the electricity. Conversely, end users consume less than the efficient level of electricity when prices they face are above the supply cost.

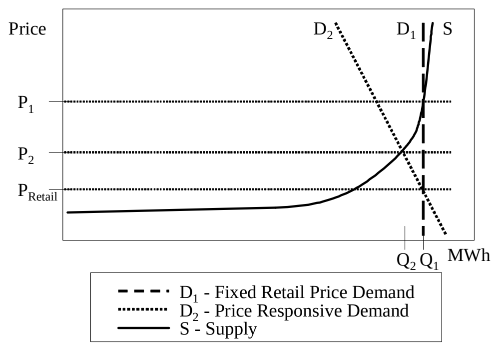
The lack of demand response also increases the ability of electricity suppliers to exercise market power and raise prices. In order to achieve efficiency in the marketplace, prices should reflect the cost of the good in the market. When firms exercise market power, prices will deviate from the cost of production. Market power contributes to the price volatility and price spikes observed in today's electricity markets. The exercise of market power also results in large wealth transfers from customers to suppliers.

This paper provides an overview of the issues relating to and importance of demand responsiveness in electricity markets. The paper first discusses the basic attributes of the energy market and illustrates the role of demand-side bidding. This is followed by a survey of various measurements of demand response that appear in the literature. The role of demand side response plays in mitigating market power is then addressed. Available rate designs relating to demand responsiveness are surveyed. The paper concludes with an assessment of the technical advances that can increase demand responsiveness in the marketplace.

II. Demand Responsiveness in the Marketplace

Currently most electricity consumers see a fixed retail rate. Their demand for electricity based on that rate. When consumers do not respond to prices, the market demand curve in the market is simply vertical line. This demand curve is vertical because the load serving entity (LSE) is required to procure the electricity for the consumer regardless of the market price. This vertical market demand curve does not reflect the value of consumption to consumers. The LSE must procure the electricity at prices which may exceed the value of electricity to its customers. Allowing consumers to adjust their consumption in reaction to prices results in a sloped demand curve where the quantity demanded naturally decreases as prices increase.

Electricity Market



The supply of electricity is shaped much like a "hockey stick" shape. Prices increase only slightly with increased demand along much of the supply curve. However, as demand approaches the supply capacity, prices to supply such quantities increase dramatically. It is in this region of the supply curve that demand responsiveness can provide the most benefits to the market's consumers.

Demand responsiveness also provides significant benefits to system reliability in during these times of scarcity. The reductions in peak demand reduces system strain, expands effective operating reserve margins, and improves voltage stability and reactive power profile.

A. Demand-Side Bidding in ISO Markets

One approach to increasing demand responsiveness is to promote demand side bidding in electricity markets. The four existing ISOs operate bid-based energy markets. The ISO determines market-clearing prices and quantities on an hourly basis based on bids submitted by market participants. The details of the auctions vary among the ISOs. For example, sellers in PJM, the New York ISO, and ISO-New England submit multipart bids (specifying start-up, minimum-load, and energy bid prices), while sellers in the California ISO submit one-part bids (specifying only energy bid prices). Also, PJM and the New York ISO operate both day-ahead and real-time auction markets, while ISO-New England and the California ISO operate only real-time auction markets. [1]

Centralized, bid-based markets can promote efficiency in energy markets. The ISO has the opportunity to select from a large supply pool in order to meet demand at least cost. In principle, the ISO also has the opportunity to select from a large customer pool in order to allocate scarce supplies to buyers that most value electricity service, and to elect not to serve certain customers when the cost to serve them exceeds their willingness to pay.

In practice, however, wholesale buyers rarely submit price-sensitive bids. Typically, buyers, or the ISO on the buyers' behalf, submit bids that state only the quantity to be purchased. On their face, these bids suggest that buyers are willing to pay any price – no matter how high – to acquire the stated quantity. Why do buyers fail to include price in their bids? Most wholesale buyers are distribution utilities that have a legal obligation to provide electricity to their retail customers. The demands of wholesale buyers are generally a mere passthrough of the demands of their retail customers. Most retail customers face fixed retail prices that don't vary with wholesale prices. Retail customers don't respond to hourly wholesale prices because they don't see or pay them.

Recently, ISO prices have shown an enormous variance over time – rising as high as $6,000/MWh and falling to $0/MWh or even into a negative range. It seems unlikely that customers would want to purchase the same amount of energy when the price is $6,000 as when the price is $0. Indeed, some customers may be financially unable to pay $6,000 for energy. For these reasons, wholesale buyers (and their retail customers) may benefit from developing the capability to submit price bids into spot energy markets. In addition, electricity prices approaching $6,000/MWh are unlikely to reflect the marginal costs of the supplier; instead, they are likely to be an attempt by the seller to exercise market power. The ability of sellers to exercise market power by asking

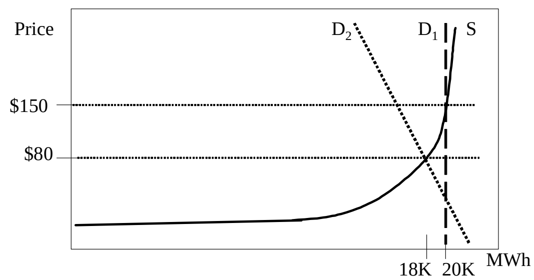
[1] The Commission has approved a proposal for ISO-New England to add a day-ahead market, but the ISO has not completed implementation yet.

for such high prices could be reduced if buyers were to submit price bids indicating an unwillingness to pay such high prices.

B. The Benefits of Demand-Side Bidding – The Basic Case

From an economic point of view, a consumer should reduce its electricity consumption if the benefit to the consumer isn't worth the costs of the most expensive unit on line. But when buyers don't submit demand bids, too much electricity may get consumed and produced, especially during peak periods. In the ISO bid-based markets,

Demand-Side Bidding Example



the market price reflects the highest accepted supplier bid. If customers don't submit price bids, the ISO may need to dispatch some very high cost units to meet demand during peak periods, even though some retail customers don't find the electricity to be worth the market price. But if customers submitted price bids, the ISO would avoid dispatching the high-cost unit to serve the marginal customer.

For example, suppose that the ISO faces a supply curve based on the supply bids it receives, as shown in Figure 1. If customers submit no price bids, then the ISO would see a vertical demand curve (D1), dispatch 20,000 MWh of electricity, and establish a price of $150/MWh that covers the marginal cost of the most expensive supplier. But if customers submit price bids that reflect their actual willingness to pay for electricity, the ISO would see a different demand curve (D2). It then would dispatch only 18,000 MWh of electricity at a price of only $80/MWh. In so doing, the ISO would avoid dispatching 2,000 MWh from units costing up to $150 that would have been used to serve customers who were unwilling to pay more than $80.

III. Measurement of Demand Responsiveness

As background, measurements of demand responsiveness appearing in the literature and how demand responsiveness is dealt with by methods used to evaluate market power are discussed.

The vast majority of literature on demand responsiveness in electric markets attempts to measure precisely the change in demand for electricity due to a change in price (price elasticity) using rigorous econometric analysis. A much less extensive, but still relevant, literature provides time-of-use pricing programs' effect on utilities' peak load. Finally, since demand responsiveness is usually associated with changes in price, the demand reduction recently experienced in California is interesting because it did not occur in normal response to a price change.

A. Price Elasticity Literature

Price elasticity – the percentage change in quantity demanded divided by the percentage change in price – is the measure of demand responsiveness universally used in economics. The reduction in quantity demanded because of a price rise may be very small, yielding a price elasticity that is a small negative number that approaches zero. Conversely, the reduction in quantity demanded because of a price rise may be very large yielding a price elasticity that is a very large negative number approaching infinity.[2] The naming convention in economics says that price elasticity is more "inelastic" as it moves toward zero and more "elastic" as it becomes a larger negative number.

Basic economic theory provides two expectations about price elasticity. First, since a higher price should reduce the quantity demanded, the price elasticity should be negative.[3] Second, since more substitution can take place when more time is given, price

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[2]As examples, a price elasticity of -.01 means that a doubling of the price (100 percent price rise) would reduce demand by only 1 percent while a price elasticity of - 50.0 means that a 1 percent rise in price would reduce demand by 50 percent.

[3]The theoretical exception would be for the so called (and perhaps totally apocryphal) "snob good" whose value to the holder depends so much on showing-off how much was paid that demand actually increases when the price is raised. Empirical estimation of positive a price

elasticity for a given product which allows little time for substitution ("short-run") will be more inelastic than when more time is allowed for substitution and the development of substitution technologies ("long-run").

Numerous studies of price elasticity in the electric industry have been published with the most recent studies generally involve time of use pricing (TOU).[4] Many techniques have been used in estimating price elasticity.[5] These differences in techniques lead to criticism and counter-criticisms over the techniques used, but no one technique has been shown to be either especially good or bad. However, two particular difficulties with price elasticity estimation has been highlighted by these debates and the general experience with the estimation of electric price elasticities.

1. Non-TOU Price Elasticity Literature

elasticity for normal goods like electricity does occur; but this indicates a problem with the data used and/or the model underlying the econometric estimation.

[4]In this paper, the term "time of use pricing" (TOU) is the general term denoting that prices vary depending upon when the electricity is used. Specific types of TOU will be defined as they appear later in this paper.

[5]For example, a 1981 survey of price elasticity studies categorized studies by types of data (aggregated, disaggregated, by industry, and whether marginal or average prices were used) and by of model (static) used – Bohi, Douglas R.; *Analyzing Demand Behavior: A Study of Energy Elasticities* (1981), Baltimore: Johns Hopkins Press.

A number of the price elasticity studies from before 1980 are captured in one of four survey articles. Eighteen elasticity studies, incorporated in two surveys by Taylor[6], led to the summary conclusions that the short-run price elasticity for aggregate electricity demand is -0.2 and the long run elasticity is between -0.7 and -0.9. A survey of 25 studies of residential demand by Bohi[7] had short-run elasticities varying from -0.03 to -0.54 and long-run elasticities varying from -0.45 to -2.1. Bohi found that the few existing studies for commercial demand indicated that long-run demand is elastic, while studies of industrial demand, which Bohi criticizes severely, have a consensus estimate of price elasticity of -1.3. From a survey of 18 studies of residential demand, Bohi and Zimmerman[8] conclude that the short-run price elasticity for the residential sector is -0.2 and the long-run price elasticity is -0.7. They further conclude that the wide variance of the elasticity estimates from available studies make it difficult to report the price elasticity for either the commercial or industrial sector.

A survey of 2 aggregate demand, 21 residential, 7 commercial, and 18 industrial studies of electric price elasticity by Dahl[9] showed wide variances in price elasticity estimates. This wide variance lead to "cautious" observations that the studies show a long-run price elasticity for aggregate demand for electricity to be near -1.0 and a long-run price elasticity for the residential sector between -0.91 and -0.75.

2. TOU Price Elasticity Literature

Most recent studies of electric price elasticity have included analysis of time of use pricing. The sample evaluated in a number these studies is described below while the range of price elasticities estimated in each of these studies is shown in Table 1.

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[6]Taylor, Lester D.; "The Demand for Electricity: A Survey," *Bell Journal of Economics*, Spring 1975, pp. 74-110; and "The Demand for Electricity: A Survey of Price and Income Elasticities," in *International Studies of the Demand for Energy*, William D. Norhaus, ed. (1977), Amsterdam: North Holland.

[7]Bohi (1981).

[8]Bohi, Douglas R. and Zimmerman, Mary; "An Update of Econometric Studies of Energy Demand,"*Annual Review of Energy*, 1984 (9), pp. 105-154.

[9]Dahl, Carol; "A Survey of Energy Demand Elasticities in Support of the Development of the NEMS," (1993) Contract De-AP01-93EI23499, U.S. Department of Energy.

Some studies deal with the effect of TOU with only a few daily prices, i.e., a price for peak usage of electricity and a price for off-peak usage. Hawdon[10] evaluated 11 studies based on 7 experimental programs where distribution companies temporarily used time of use prices to the residential sector. Filippini[11] estimated peak and off-peak price elasticities using a detailed set of characteristics for 220 Swiss households. Park and Action evaluated data for large customers of ten utilities.[12] Scharz estimated the elasticity of demand from Michigan businesses.[13] Woo evaluated the demand of 64 small non-residential customers in Southern California.[14] Tishler (91)[15] evaluated the demand of two industrial firms in Southern California under time of use pricing. Tishler (98)[16] estimated electric price elasticities using data from 500 small to medium sized Israeli business. The sample evaluated in a number these studies is described below while the range of price elasticities estimated in each of these studies is shown in Table 1.

Table 1. Ranges of Price Elasticity Estimates for Time of Use Studies

Study	Residential				Business			
	Peak		Off-peak		Peak		Off-peak	
	Most Elastic	Least Elastic	Most Elastic	Least Elastic	Most Elastic	Least Elastic	Most Elastic	Least Elastic

[10]Hawdon, D.; "Is Electricity Consumption Influenced by Time of Use Tariffs? A Survey of Results and Issues," *Energy Demand: Evidence and Expectations* (1992).

[11]Filippini, Massimo; "Electric Demand by Time of Use: An Application of the Household AIDS Model," *Energy Economics*, July 1995 (17), pp. 197-204.

[12]Park, R. E. and Action, J. P.; "Large Business Customer Response to Time-of-Day Electricity Rates," *Journal of Econometrics*, 1984 (26), pp. 229-252.

[13]Schwarz, P.; "The Estimated Effects on Industry of Time-of-Day Demand and Energy Electricity Prices," *Journal of Industrial Economics*, 1984 (32), pp. 529-539.

[14]Woo, C. K.; "Demand for Electricity of Small Nonresidential Customers under Time-of-Use (TOU) Pricing," *Energy Journal*, 1985 (6), pp. 115-127.

[15]Tishler, Asher; "Complementarity-Substitution Relationships in the Demand for Time Differentiated Inputs under Time of Use Pricing," *Energy Journal*, 1991 (12), pp. 137-148.

[16]Tishler, Asher; "The Bias in Price Elasticity Under Separability Between Electricity and Labor in Studies of Time-of-Use Electricity Rates: An Application to Israel," *Energy Journal*, 1998 (19), pp. 217-235.

Hawdon[6]	positive	-0.80	positivee	-0.90				
Filippini[7]	-1.50	-1.25	-2.57	-2.30				
Park and Action					-0.25	-0.00		
Schwarz					positive	-0.07		
Woo					-0.04	-0.03	-0.05	-0.03
Tishler (91)[8]					-0.09	-0.04	-0.06	-0.02
Tishler (98)[9]					-0.47	-0.01	-0.38	-0.02

Notes: (1) Some studies provided results such as the price elasticity of the mid-peak that are not reported here.
(2) Results are not reported for methodologies that the study determined to be deficient.
(3) “pos” indicates that the estimation produced the theoretically invalid result of a positive elasticity – see footnote 2 and associated text.

Other studies deal with the effect of the more complex dynamic pricing. Dynamic pricing can involve the supplier providing a set of 24 hourly prices in periods of either one day ahead or one to two hours ahead. Real-time pricing (RTP) refers to a form of dynamic pricing that is based on current market conditions.

There have been numerous dynamic pricing programs. In the mid-1980s some electric utilities adopted small RTP programs. A study done by Newcomb and Byrne [17] identified 29 North American utilities with real-time pricing programs. These programs were aimed primarily at large industrial customers with some large commercial customer participation. The hourly programs were complicated as they were run by integrated utilities under cost-of-service regulation. In Mak and Chapman's review, four of these utilities conducted customer surveys and found that high prices indeed induce customers to reduce loads significantly, despite the fact that the hourly pricing programs differed significantly. [18]

[17] J. Newcomb and W. Byrne, *Real-Time Pricing and Electric Utility Restructuring: Is the Future “Out of Control?”* SIP, E Source, Boulder Co. April 1995.

[18] J.C. Mak and B.R.Chapman, “A Survey of Current Real-Time Pricing Programs,” *The Electricity Journal* , Vol. 6, pp. 54-65, 1993.

Patrick and Wolak [19] analyzed customer data from medium and large industrial customers in five industries participating in purchasing electricity on the basis of half-hourly prices in England and Wales power the period 1991 through 1995. They found that price elasticities varied considerably across industries and the pattern of within-day substitution in electricity consumption. During high price periods, they found that, despite small elasticities, significant load reduction occurs for these participants. Price elasticities were reported only for the most price elastic industry – the water supply industry; these price elasticities ranged from -0.142 to -.27.

Another study in England, King and Shatrawka, [20] found that dynamic pricing there produced more significant inter-day load shifting, with price elasticities ranging from 0.1 to 0.2, than intra-day load shifting, with price elasticities ranging from 0.01 to 0.02. They found that between 33 percent and 50 percent of participating customers responded to time-varying prices.

Currently Georgia Power operates the largest dynamic pricing program in the United States where 1,600 industrial customers with about 5,000 MW of load participate. Commercial customers constitute about 15 percent of the program load. Georgia Power offers day-ahead or hour-ahead firm price notices. The utility posts the day-ahead price, based on it's expected hourly marginal cost plus $4/MWh at 4 PM by e-mail or the Internet. The hour-ahead price is set at the next hour's expected marginal cost plus $3 because the utility's risk that the price will not be accurate is lower for these prices than the day-ahead prices. The price response of this program has been significant.

The utility reported much greater load reduction on-peak compared with on-peak load reductions under its historical fixed-price method. Georgia Power also reported that as wholesale price volatility increased, customers did not abandon the day-ahead or hour-ahead firm price options. Instead, many have purchased risk management tools such as contracts for differences, caps, or collars protecting certain loads during specific time periods.

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[19] R.H. Patrick and F.A. Wolak, "Estimating the Customer- Level Demand Under Real-Time Market Prices," draft, Rutgers University, 1997.

[20] K.King and P. Shatrawka, "Customer Response to Real-Time Pricing in Great Britain," *Proceedings of the ACEEE 1994 Summer Study on Energy Efficiency in Buildings*, Washington, DC August 1994.

Participants in the hour-ahead program exhibited greater demand elasticity than day-ahead program participants: hour ahead customers had a demand elasticity of -0.154, - 0.171, and - 0.189 for prices of $0.25/kWh, $0.50/kWh, and $1.00/kWh, respectively. For very high prices, participating industrial customers in the hour-ahead program reduced their electric load by 29 percent and 60 percent for increases in the maximum daily price to the $300 - $350/MWh range and $ 1,500 - $ 3,000/MWh, respectively. Day-ahead participants exhibited significantly smaller demand elasticities, ranging from a half to a tenth of the demand elasticities of day-ahead participants across the price levels of $0.25/kWh to $1.00/kWh. For very high prices, day-ahead participants reduced their load by 8 percent and 20 percent for price increases to the $300 - $350/MWh range and $1,500 - $2,000/MWh range, respectively.

Some utilities have also offered residential customers dynamic pricing options. Braithwait reports that GPU initiated a time-of-use pilot program for residential customers where the utility communicated price signals to home thermostats that could be set to automatically adjust to these signals. During the summer months, these residential participants reduced their weekday electricity consumption by 7 percent on average. The overall elasticity for these residential customers was about 0.30, much higher than the elasticities reported in other residential time-of-use programs.

More recently, The New York ISO implemented an Emergency Demand Response Program in the Albany area during the summer of 2001. About 70 MW of retail load participated in the program on an hourly basis. During peak demand periods participants would be notified to reduce load and receive the higher of $ 500/MWh or locational marginal price (LMP) times the amount of load reduction. The load reduction program produced significant savings, particularly during a 4-day heat wave in early August. Participants reduced total load by 3.5 percent. A consultant determined that wholesale electricity prices would have been 32 percent higher absent this load reduction. The Emergency Demand Response Program supplied over 425 MW during the summer of 2001. The program is estimated to have resulted in realtime whole-market value savings of $13 million. Total program payments were $4.2 million [21].

3. Difficulties in Price Elasticity Estimations

Experience in estimating price elasticities has highlighted two major difficulties. First, the estimate of price elasticity will be biased if substitution of other inputs for the

[21]Neenan Associates, "NYISO PRL Program Evaluation," January 15, 2002, pp E-6.

use of electricity occurs but is ignored by the model used to make the price elasticity estimation. (Of course, such inclusion requires a more complex model with the corresponding difficulties involved.) The theoretical possibility of such bias has long been known.[22] Empirically, modeling of the substitution of labor for electricity raised the elasticity estimates for the Tishler studies from the least elastic to the most elastic estimations reported in Table 1.

Second, price elasticity seems to vary widely across different industries. Therefore, a region cannot expect demand response from the industrial sector to match that of another region unless the mix of industries is similar.

B. Effect on Peak Utility Load of TOU Pricing

Some utilities have instituted time of use pricing for utilities. Georgia Power's time of use pricing has been reported to have 1,600 customers and reduced peak load by 17 percent on the most expensive days.[23] Other reported changes in peak load are shown in Table 2. While other factors which may have affected demand have not been accounted for, these results indicate that a utility's peak load will be decreased if time of use pricing is implemented.

Table 2. Customer Load Response to Highest Priced Hours of Time of Use Pricing

Year	Utility	MW Reduction	Percentage Reduction	Highest Price ($/kWh)	Customers as of 2/93
1988	Pacific Gas & Electric	1.0 - 1.7	5 -9	0.40	23
	Southern California Edison Co.	0.8	7	1.36	15
	Niagara Mohawk Power	18	36	0.24	38
1989	Pacific Gas & Electric	0.5	3	0.39	

[22]For example, this issue was debated in six articles in the *Journal of Business and Economic Statistics*, July 1983 (1), pp. 202-28.

[23]Levesque, Carl J.; “Real-Time Metering: Still as Sweet with Prices Controlled?,” *Public Utilities Fortnightly*, September 1, 2001, p. 16.

	So. California Edison - program 1	-0.2	-3	1.36	
	So. California Edison - program 2	1.1	16	2.70	
	Niagara Mohawk Power	22	20	0.50	
1990	Pacific Gas & Electric	1.5	10	0.39	
	Niagara Mohawk Power	12	12	0.14	
Source: Mak, Juliet C. and Chapman, Bruce R.; "A Survey of Current Real-Time Pricing Programs," *Electricity Journal*, August/September 1993, pp. 55 and 63.					

Caves and Christensen[24] evaluated how customers altered their loads in response to a retail peak-load pricing program in Wisconsin. The customers were found to be quite responsive in altering their load. The program confronted different customers with peak/off-peak price ratios ranging from 2:1 to 8:1, while the length of the peak period varied from 6 to 12 hours in duration. Even though customers were told that a participant's bill would not change if they continued their prior consumption pattern, they altered their consumption considerably. Customers facing a 2:1 peak/off-peak ratio reduced their consumption of electricity during summer months by 11 percent to 13 percent, while those customers facing an 8:1 price ratio reduced their consumption by 15 percent to 20 percent during the summer peak periods. Moreover, this study found there was greater shifting of load on critical days to off-peak periods during heat waves with reduction in consumption up to 31 percent compared with non-peak days. Caves and Christensen found that customers reduced their consumption of electricity more during the time of the system peak than during the remainder of the peak pricing period in the summer compared to the winter. Customers were more willing and able to shift their midday usage (the time of the summer peak period) than their evening usage (the time of the winter peak period). They also found that the time of use pricing encouraged conservation as customers reduced their overall consumption of electricity over the combined summer and winter pricing periods.

C. Recent Experience In California

[24] Douglas W. Caves and Laurits Christensen, "Time-of-use Rates for Residential Electric Service: Results from the Wisconsin Experiment," *Public Utilities Fortnightly*, Vol. 111(March 17, 1983), pp. 30-35.

Although the focus on demand response is usually related to price changes, electricity demand is a function of other things in addition to prices. A recent striking example of this is the significant drop in electricity demand in California. Demand from February to May of 2001 averaged over 4.9 percent less per month than the corresponding months of 2000 (with figures weather adjusted). “Since retail electricity prices did not rise significantly until June 2001 we must attribute the decline in demand, in part, to the effects of all the publicity about electricity on consumer behavior and the formal energy conservation programs implemented by the state.”[25] While such reductions due to public awareness deserve attention, the fact remains that pricing signals are the most effective approach to rationing supply shortages. In fact, on February 16, 2001, the California Governor Gray Davis conceded: "Believe me, if I wanted to raise rates, I could have solved this problem in 20 minutes."

[25]Joskow, Paul L., “California's Electricity Crisis,” updated September 28, 2001, pp. 46 and 64.

IV. Demand Elasticity in Market Power Analysis

A. The Impact of Market Power on Unresponsive Markets

When there is a demand side response to prices, customers signal to the market the value they place on electricity. Unfortunately, the prices paid on the wholesale market for electricity are not signaled to the end-use customers. An inaccurately high signal of value is sent to the wholesale market since customers do not reduce their consumption even as the price rises. This high valuation is inaccurate, because these customers are not actually paying the market price. The customers are facing a fixed price (often a proxy for the average price) which bears little short-term relationship to the wholesale price volatility of electricity. This leads to one source of inefficiency in electric markets.

When the demand side of the market, i.e., the customers, do not react to market prices, all pricing mechanisms are left in the hands of the market suppliers. In the presence of competition, the suppliers will, on their own, be unable to raise prices above the production cost of the least efficient unit operating. In this competitive situation the market price will adequately reflect the production costs.

However, suppliers are able to set prices above the cost of the last unit when they have market power. The suppliers' ability to raise prices above costs increases with lower demand responsiveness. Unfortunately, this pricing behavior further reduces the efficiency of the market by creating an even larger wedge between the actual production costs of electricity and its value to customers.

The exercise of market power also results in large price spikes and increased price volatility. In times of electricity shortage, suppliers literally have the opportunity to “name their own price.” These prices above cost result in large wealth transfers from electricity buyers to sellers. While these wealth transfers may not necessarily affect short-run efficiency in the market, the equity of such activity can be debated.

B. The Commission's Current Analysis

Currently the Commissions has not incorporated demand responsiveness in its evaluation in market power and merger analysis. This may be of increased importance in the future as impact demand response programs in the markets increase. Additionally, the Commission could help promote the importance of demand responsiveness in the market place addressing its role in mitigate the adverse effects of market power.

1. Supply Margin Assessment

The Commission has adopted the Supply Margin Assessment (SMA) test for analyzing markets for Market Based Rate applications.[26] The SMA determines whether a seller is pivotal in the market, i.e., whether the market's peak day demand can be met in the absence of the applicant's generation. To the extent this is true, the applicant would not be able to withhold production or unilaterally demand higher prices, thus exercising market power. The SMA compares the applicant's generation capacity to the difference between available supply and peak day demand. Available supply includes all of the applicant's generation capacity as well as competing suppliers' uncommitted capacity that can reach the market once transmission constraints are factored in. If the applicant's generation is less than or equal to the effective reserve margin (the remaining supply after the peak demand is met), that applicant would not have the ability to exercise market power since its generation would not be needed to meet the market's demand. The SMA does not consider demand elasticity. There is an implicit assumption that demand is perfectly inelastic, thus if any of the firm's capacity is needed to meet peak demand then that firm has market power, unless it is mitigated by the market rules.

2. Delivered Price Test

For merger and generation transfer applications, under Section 203 of the FPA, the Commission uses the Delivered Price Test (DPT) to analyze the competitiveness of relevant wholesale electricity markets. The DPT identifies suppliers that can reach a destination market at a cost of no more than 5 percent over an assumed price. If a seller's generation can reach a destination market, including the cost of delivery, within 5 percent of the destination market price, the supply is considered economic. Scarce transmission

[26]See Order on Triennial Market Power Updates and on Addressing Interim Market Screen and Mitigation (SMA Order). Docket Nos. ER96-2496-015, ER91-569-000 and ER97-4166-008. November, 2001.

availability is usually allocated among competing suppliers on a *pro rata* basis. An *economic* (least cost) allocation of scarce transmission availability can also be used (for example, to simulate the least-cost dispatch of an RTO). Demand levels are reflected by the choice of the destination market price, but the DPT does not explicitly consider demand elasticity.

C. Other Tests for Market Power

1. Residual Supply Index

The Commission also considered using the Residual Supply Index (RSI) for analyzing markets for Market Based Rate applications. The RSI is used by the California ISO to determine the extent an individual supplier's generation capacity is needed to meet market demand in a given hour. The RSI for each supplier is calculated by dividing the total supply offered by all generators other than the supplier in question by the quantity demanded in a given hour. If the total quantity demanded cannot be met by the residual suppliers (indicating an RSI < 1) then, a supplier is a pivotal bidder. In that case any bid submitted by the supplier would have to be accepted. All else equal, as the RSI decreases, market power increases. The RSI does not allow for demand response to price. As with the SMA, there is an implicit assumption that demand is perfectly inelastic.

2. Hub and Spoke

For market-based rate (MBR) applications, under Section 205 of the Federal Power Act (FPA), prior to the SMA Order, the Commission used the Hub and Spoke (H&S) methodology to analyze the competitiveness of relevant wholesale electricity markets. Under the H&S, the destination market, or hub, is defined as the location of the generating unit that is seeking MBR authority from the Commission. All generating units directly interconnected with the hub (the spokes) are considered as potential suppliers in the market. There is no consideration given to the demand elasticity of the customers or even the level of demand at any given price.

D. Equilibrium Models

An equilibrium model solves for a price that equates quantity supplied and quantity demanded. Any equilibrium model would have to include a demand function.

Therefore, demand elasticity would have to be considered. For example, given a linear demand curve, P = a - bQ, and a constant marginal cost (c), where a>c, e = demand elasticity, n = the number of firms and assuming Cournot behavior in the Oligopoly case:

Table 3. Industrial Structure and Market Price Equilibrium

	Equilibrium Price (P)	Equilibrium Quantity (Q)	Price-Cost Margin (p-c)/p (Lerner Index)
Cournot Oligopoly	(a+nc)/(n+1)	n(a-c)/((n+1)b)	-1/ne
Monopoly	(a+c)/2	(a-c)/2b	-1/e
Perfect Competition	c	(a-c)/b	0

The Lerner Index measures the firm's ability to raise price above marginal cost (that is, to exercise market power). As the number of firms increases, all else equal, the Lerner Index decreases. The Monopoly case is the Oligopoly case where n=1 while the Perfect Competition case is the Oligopoly case where n = 4. Also, as shown above, the more elastic the demand function, the lower the Lerner Index.

While harder to construct than structural models, equilibrium models reflect the price and quantity effects of demand-side response. If the Commission considered demand elasticity in its analysis of market power, then applicants for MBR or Section 203 approvals could offer improvements to demand side response as market power mitigation. Applicants would then have options other than structural approaches such as divestiture or behavioral approaches such as must-offer requirements or cost-based rates.

1. The Commission's Proposed Use of Computer Simulation Models for Market Power Analysis

On April 16, 1998, the Commission issued a notice requesting written comments and expressing its intent to convene a technical conference regarding the use of computer simulation models for merger analysis.[27] In it, the Commission asked whether demand should be made responsive to price and, if so, what would be the appropriate demand

[27] Inquiry Concerning the Commission's Policy on the Use of Computer Models in Merger Analysis (Modeling Inquiry). Docket No. PL98-6-000. April 16, 1998.

elasticity.[28] Among the responses, the U.S. Department of Justice stated that some responsiveness to price should be a feature of the models, but noted it is not clear how it should be modeled.[29] The University of California Energy Institute supported the Commission's proposed use of computer simulation models. It offered examples of how an equilibrium model, one that includes demand curves and solves for the Cournot-Nash equilibrium, can give better insights into the workings of an electricity market than can structural measures such as market concentration.[30]

2. Available Commercial Models

There are equilibrium models currently available. One, General Electric Multi Area Production Simulation (GE-MAPS), allows for demand-side bidding, along with multi-step cost functions, unit cycling capabilities and emission characteristics.[31] GE-MAPS has been used for calculating the inputs for the DPT in a generation asset sale that was approved by the Commission.[32]

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[28]Modeling Inquiry at 22.

[29]Comments of the United States Department of Justice at 6.

[30]The Cournot-Nash equilibrium requires that each producer chooses the output level that maximizes its profits given the output levels of all the other producers.

[31]The demand side price response would be modeled as a dispatchable demand which would be interrupted if the market price reached a threshold.

[32]New Albany Power I, LLC, and Duke Energy North America, LLC, Docket No. EC01-128-000. September 2001.

V. Retail Participation in Wholesale Electric Markets

Retail customers are currently insulated from volatile wholesale electricity prices. Most retail prices are set in advance and are time-invariant. One way to reform this pricing is to separate the retail rate into two components: (1) the electricity commodity and (2) the insurance premium that protects customers from price changes and allows them to consume unlimited amounts of electricity at any time. In some states, however, customers have been offered pricing options that better reflect volatile wholesale electricity prices. These pricing options are attempts at providing better information on the underlying variability in the cost of producing electricity. Customers, in the face of volatile electricity prices, can choose to undertake risk management tools to ensure a particular price, insure themselves or they can modify electricity use in response to changing prices.

There is evidence from many of these alternative pricing options that retail customers respond by choosing to modify consumption in response to changing prices. Many retail customers have reduced demand or shifted it to off-peak periods. This has improved the operating efficiency of those systems by lowering the size of price spikes and helping to discipline the ability of generators to raise prices during peak demand periods. Thus, all customers benefit from these consumption changes. This section discusses the effects of alternative rate designs that have been adopted by states and other countries.

A number of rate design options may be offered to customers to realize greater efficiency in electricity consumption. Costs include relaying information on prices of producing and transmitting electricity. A rate design using more refined and timely information will be more costly than a rate design using less refined and timely information. The benefit to various retail customers can vary significantly. Thus, different types of retail customers may choose alternative rate designs.[33]

One would expect that the larger the load, the more economic is a sophisticated pricing option as the metering and other costs to implement this option are outweighed by the energy savings from changes in electricity consumption patterns. For example, a large industrial customer may find it more economic to incur the costs of installing real-

[33] France offers retail customers an array of rate design choices ranging from peak load to real-time pricing. See Jean-Jacques Laffont, "The French Utility Industry," Chapter 10 in *International Comparisons of Electricity Regulation*, Cambridge University Press, 1996.

time metering; while a small low voltage residential customer will most likely not consider incurring these costs. The individual residential load is so small that any load responsiveness to real-time prices may not outweigh the metering costs. However, this does not mean that retail customers should not be offered the more sophisticated option. Some individual customers may find it attractive, or they may be able to aggregate other retail load in order to make the option economic.

This section discusses the array of rate design options that have been used to send more efficient price signals to retail customers.[34]

A. Peak Load Pricing

Peak load pricing is a lower cost way to encourage retail customers to shift their consumption from periods of peak demand to off-peak demand periods, or lower their consumption on-peak. The basic idea is to vary the rate with the system peak; raising the rate during periods of peak demand during the day (typically the early morning and early evening) and lowering it during the off-peak period. The intent is to alter electricity consumption patterns, shifting load to the off-peak period(s) thus reducing or delaying the need for new generation capacity. Metering sufficient to measure peak and off-peak electricity consumption is necessary to implement this program.

The costs to implement this rate design involve collecting information on retail load consumption patterns and the short-run electricity production costs to meet this load, which is primarily fuel cost and operation and maintenance costs. A disproportionate level of costs is then assigned to the peak load period(s). One way of implementing this approach is to estimate long-run incremental cost of capacity expansion (LRIC) and design rates such that the price during the peak demand period generates sufficient revenues in excess of the LRIC of capacity expansion to compensate for the revenue deficiency generated during off-peak periods when price is below LRIC. [35]

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[34] This discussion relies on the recent survey by Eric Hurst and Brendan Kirby, Retail-Load Participation in Competitive Wholesale Electricity Markets, prepared for the Edison Electric Institute, January 2001.

[35] Oliver Williamson, “Peak-Load Pricing and Optimal Capacity under Indivisibility Constraints,” *American Economic Review*, Vol. 56 (September 1966), pp. 810-827. Important precursors to this work are Marcel Boiteaux, “Peak-Load Pricing,” *Journal of Business*, vol. 33 (April 1960), pp. 157-179 and Peter O. Steiner, “Peak Loads and Efficient Pricing,” *Quarterly Journal of Economics*, Vol. 71 (November 1957), pp. 585-610.

Allocative economic efficiency gains occur as retail customers may consume less during the peak periods, shifting their consumption to off-peak periods, or reduce their total consumption during the year. The amount retail customers respond to higher peak prices depends how price-responsive they are (i.e., how elastic their demand for electricity is). Productive efficiency gains occur in the short run as utilities (or independent generators having a portfolio of units) operate their more efficient generating units at a higher level of utilization. Long-run efficiency gains also occur from avoiding the strain of peak capacity use and thus delay the need for replacing existing generating units.

This rate design is a less sophisticated option because, as it is based on historical data perhaps combined with long-term weather forecasts, it captures only the general expected volatility of electricity production costs throughout the peak and off-peak periods. Efficiency can be further enhanced if prices reflect the daily and intra-daily cost changes that occur within the peak and off-peak periods to meet volatile demand. Better metering is necessary to measure these production cost variations and translate them into timely price signals to customers.

B. Dynamic Pricing

One attractive way to accomplish a more sophisticated rate design is through the use of dynamic pricing. Dynamic pricing can involve the supplier providing a set of 24 hourly prices in periods of either one day ahead or one to two hours ahead. Real-time pricing (RTP) refers to a form of dynamic pricing that is based on current market conditions.

C. Interruptible Load and Voluntary Load Reductions

Over the past 20 years, utilities have offered ways mainly to large industrial and commercial customers to reduce demand during peak demand days. These programs do not rely on the more accurate price signals that serve as the basis for dynamic pricing options. Thus, they are less costly to adopt. Generally, these programs specify well in advance the maximum times a year the utility can call for interruptions, the advance notice required, the maximum time period for each interruption, and the penalty imposed on customers failing to comply with the program terms and conditions.

Plexus Research surveyed 89 of these programs covering about 7,000 industrial and commercial customers. Plexus also surveyed 333 load control programs mainly involving residential water heater and air conditioners. ISOs and electric utilities have adopted a variety of load reduction programs, mainly voluntary. For example in the summer 2000, New England solicited three 200-MW blocks of interruptible load at prices of \$500, \$750 and \$1,000/MWh. The higher the price level, the shorter the load reduction duration that is required. Blocks of demand participating in this program are called upon when the forecast market-clearing price exceeds one of these set levels. California also has had a similar program in effect. The programs can help reduce load during peak periods. However, they do not help send accurate price signals. Also, they are of limited use if the electric system is facing a sustained number of critical periods because the utility can quickly reach the number of days that the customer may be called upon to reduce load. This occurred in California during the past year.

VI. Technical Issues in Demand Responsiveness

Increases technology regarding controls systems, telecommunication, and metering all increase the opportunity for end users to monitor and adjust their electricity consumption in coordination with electricity market conditions. Additionally, distributed generation is an important source of supply as when traditional supply sources become scarce. These result in more efficient electricity consumption and increased system reliability. Developing these alternatives and incorporating them into the market place is increasingly becoming a reality and should provide increased demand-side responsiveness in the future.

A. Control Systems, Telecommunications and Metering Technology

Demand responsive control systems integrate the controls for the distributed (demand responsive) energy system with electronic communication and metering technology to facilitate one-way or two-way communication between utility and customer equipment. These technologies are used to reduce energy use (by dimming lights, raising air-conditioning setpoints, etc.) in response to peak electricity demand emergencies and/or prices.

For demand responsiveness, it may be important, not only for the responsive load, but also for the load serving entity, the transmission provider and load responsive generators to be able to obtain accurate real-time load data, along with concurrent real-time electric market data. The required frequency of telemetry, level of detail and accuracy of load data will vary, depending on the type of planned response that the load and generation intend to make, along with the amounts of informed risk that the responsive load, load serving entity, the transmission provider and the responsive generator are willing to take.

Since load serving entities and transmission providers will likely use the metered data not only for operational, but also billing purposes, it is important that the core components be of billing quality, including current and potential transformers ("CTs" and "PTs," respectively) and the meter itself. The type of meter needed is what is known as an "interval" meter. This meter is different from the induction watt-hour "integral" meter that might be familiar at home. The integral meter simply measures the amount of energy used. A utility sends a meter reader to record the watt-hours of energy that the meter currently reads. Subtracting the previous read from the present one provides the utility with the amount of energy used over the period of time between reads. If you stand at your home's meter and read and record the energy used over set periods of time (say 10 minute periods), then you would be recording the 10 minute integrated demands that your home's load places on the utility. It is these integrated demands over preset time intervals that interval meters read and record, along with the time and date. So an interval meter that is recording 10 minute demands will read and record the integrated demand 144 times each 24-hour day, along with the time associated with each read.

In addition to these basic components, demand responsive meters should also include secure communications capability for the use of the load serving entity and transmission provider and separate customer accessible communication data ports for customer use. The secure data port is required to prevent customer tampering with the utilities right to collect billing information from the customer, similar to the locking tab utilities typically use on residential electric meters. If the load is simply participating in demand response programs as a direct controlled load, an interruptible or a curtailable load (one that is switched off or disconnected by a load serving entity or transmission provider), the controlling entity may be able to provide the control signal via radio. If the controlling entity will be crediting the controlled load based on its performance, the controlling entity will need to have a measure of the load's demand both before and after a disconnect signal is sent. If the controlling entity is willing to take a calculated risk with regard to the load's performance and simply provide the load with a participation incentive, then the measured response performance may not be required.

If the load is participating in more advanced demand response programs such as demand bidding or buyback, time-of-use or real-time pricing, the metering package might also need to have the ability to receive price and send response signals from and to the load serving entity and/or the transmission provider.

Along with the above mentioned communications capability, if metered data are uploaded in batches to the load serving entity or transmission provider periodically, the demand response metering package may also need secure, tamper-proof data storage capability. The size of the storage will depend on the amount of data that is batched prior to transmission, and the amount of backup capability that might be necessary in case of a communication equipment failure. If the utility uses dedicated communication lines, wireless transmission, or internet connection, with little probability of failure, batch uploading of data and thus data storage may be unnecessary.

All this communication that is done securely for control and billing purposes would most likely require a completely separate communication network from the one that a customer may use to make and communicate its own power and load management decisions. The only component that both the customer and utility would share is the meter itself.

Through the customer communication data ports on the meter, the customer could integrate its power and load management information for its own use or for use by a third party load aggregator. In addition, the meter's communication data ports could provide the load with the signals that it would use to initiate load responsive actions. These may need to be managed through a customer operated control system. The customer could minimize its communication costs by using a micro computer with internet capability.

B. Distributed or Backup Generation

(source - www.distributed-generation.com)

Distributed Generation ("DG") may include reciprocating engines, microturbines, and combustion gas turbines. These resources provide the opportunity for end-users to self-supply energy or provide energy to the marketplace in times of scarcity. Many loads already require higher quality and more reliable power than utilities can offer. By tapping into this preexisting market where the need for distributed generation is driven by power quality and reliability needs of the load, transmission providers may be able to find resources that are willing to bid into a demand response market.

Demand responsive load, when coupled with distributed generation to provide continued load operation may improve the reliability of that load's service by preventing power disruption. It may also provide the load with a wider choice of power supply options and may be developed more quickly than central station generators. It has the potential to save energy producers and customers money by participating in congestion management systems, and installed capacity and operating reserve markets.

Distribution of capacity resources may ensure reliability of energy supply, increasingly critical to business and industry in general, and essential to some where interruption of service is unacceptable economically or where health and safety are impacted. Placing alternative power resources close to where the power is needed provides the right energy solution at the right location. Distributed resources may also improve the power quality for industrial applications dependent upon sensitive electronic instrumentation and controls. When valuing the benefits that distributed resources bring to the market, efficiency gains for on-site applications by avoiding line losses, and using both electricity and the heat produced in power generation for processes or heating and air conditioning should also be counted. Distributed resources may produce savings on electricity rates by allowing loads to self generate during high-cost peak power periods in addition to adopting relatively low-cost interruptible power rates.

E. State of the Art and Standard Technology

1. Demand Response Equipment Improvements

The potential for future improvements in technology lies in the areas of improving efficiency, durability, and reliability of distributed resource equipment; improving emission levels obtained through controlling technologies; and reducing installed costs through mass production.

2. Improvement in the Distributed Resource/Demand Response Marketplace

Standard interconnection rules, resource operating guideline and valuation of capacity resources that improve the reliability and economic efficiency of the electric market will decrease existing regulatory uncertainty. The deregulated market should take concrete steps to recognize the benefits that distributed capacity has in improving transmission and distribution constraints overall grid reliability and be prepared to pay a fair price for these improvements. The increased complexity of load and the demand for quality power delivery may continue drive end-users to apply distributed resources for their own economic needs.

VII. Conclusion/Summary

Past market designs and regulation have not promoted innovations in developing opportunities for demand side responses in electricity markets. In fact, many market rules in place today within ISO's result from the lack of a real demand response. These rules are poor substitutes for the benefits obtained from real demand response. The volatility in wholesale has demonstrated the importance of a demand response in times of scarcity. Demand responsiveness plays a vital role in increasing efficiency and reducing price volatility in the electricity markets. It allows customers to communicate the value of electricity to the market. Increased demand responsiveness also helps mitigate the adverse price effects of market power. Currently, advances in technology are leading to innovative pricing structures and generation alternatives to allow customers to better coordinate with the marketplace. Additionally, increased responsiveness on any individual consumer's part can benefit all consumers through their impact on the overall market and such ability should be encouraged to promote efficiency and stability in electricity markets.